

# Modeling Report

(Assuming a Permeability of 80.9 md)  
and Treating the EW-4400-S Fault  
As Non-Transmissive)

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## **Introduction**

By an interim order dated December 12, 2008, the Texas Commission on Environmental Quality (TCEQ) instructed the State Office of Administrative Hearings (SOAH) to abate the hearing on TexCom Gulf Disposal, LLC's (TGD's) Application for Underground Injection Control (UIC) Permit Nos. WDW410, WDW411, WDW412 and WDW413 in order for an analysis to be conducted using a permeability of 80.9 millidarcies (md) and an assumption that the EW-4400-S fault is non-transmissive. The permeability of 80.9 md is from an injection test conducted on Well WDW-315 (which would be re-authorized as Well WDW-410) in December 1999. This permeability is lower than the permeability determined from a core analysis on the Lower Cockfield formation discussed in the TGD Class I injection well permit application, which showed permeability values between 550 md and 850 md. The lower permeability value of 80.9 md is due to the fact that the well was perforated in the shaley portion of the wellbore, and not in the sand sections where the well cores were obtained during drilling. The 80.9 md value is therefore not representative of the true formation parameters that will be open for injection once the well is reperforated in the correct portions of the reservoir.

This report provides the details of a modeling effort performed in accordance with TCEQ's December 12, 2008, interim order, using the 80.9 md permeability value and an assumption that the fault to the south of the site (EW-4400-S) is non-transmissive. The results are provided in this write-up, and copies of the model input and output files are attached in an appendix. In addition, the impact that the results of this modeling would have on the area of review (AOR) is discussed, and copies of a map showing what the AOR would be as a result of this modeling and additional well files are included with this report.

## **Reservoir Modeling**

### **Reservoir Model**

The modeling exercise was done using the same reservoir model utilized in the TGD Class I Injection Well Application – BOAST98. BOAST98 was used to evaluate reservoir performance. The original BOAST was released in 1982 by the U.S. Department of Energy. BOAST II (Franchi, 1987) was released in 1987 (see Appendix 2, TGD Class I injection well application), and it was designed to overcome the limitations of the original BOAST. Features were added which would improve the versatility of the program. In 1995, BOAST II was modified to accurately simulate the conditions encountered in steeply dipping high permeability reservoirs. The modified model, named BOAST 3-PC, is used for performing evaluation and design work in modern petroleum reservoir engineering. Many features were added to improve the versatility of the model. BOAST98 (Heemstra, 1998) was released in 1998. The new model improved the user interface with a Windows interface. A copy of the information on the model is included in Appendix 2 of Volume I of TGD's Class I injection well application.

The reservoir evaluation is based on several variables: finite-difference, implicit pressure, and explicit saturation, with options for both direct and iterative methods of solution. The reservoir is described by three-dimensional grid blocks and by three fluid phases. Other options include steeply dipping structures, multiple rock and PVT regions, bubble point tracking, automatic time step control, material balance checking for solution stability, multiple wells per grid block, and rate or pressure constraints on well performance.

### **Modeled Injection Rate**

For this modeling effort, modeling of injection at the facility considered only one output time frames: 30-year injection (anticipated facility life). Projected injection is modeled with one well centered in the model grid. A constant injection rate of 12,000 barrels per day for the well is modeled for the entire 30 year anticipated facility life. This yields an injection rate of 350 gpm, 24 hours a day, 7 days a week which is considered conservative (i.e., actual injection volumes are expected to be much less than modeled amount) based on the anticipated operation of the well.

### **Reservoir Mechanics**

The reservoir mechanics of the Cockfield formation were modeled using a flow model to simulate the changes in the reservoir properties due to injection at the TGD WDW-315 well. The geology of the area which was modeled was discussed in detail in Section VII of the TGD Class I injection well application.

In addition to the geological information, the input parameters were also collected from the model in the TGD Class I injection well application and utilized as needed in this modeling effort. These parameters included:

- Injection interval layer thickness, permeability, porosity, structure, and compressibility;
- Original formation fluid viscosity, density, and compressibility; and
- Initial formation pressure.

### **Injection Reservoir Parameters**

#### **Injection Reservoir**

The following table presents the information on the injection reservoir identified from electronic logs performed on the injection well and additional data collection performed on the subject area. The injection reservoir is contained within the injection zone identified above. The identified injection reservoir used in the modeling effort relative to the layers presented in Table VII-1 is described below.

**TABLE 1**  
**Injection Reservoir Layer**

Formation	Layer Top Depth (ft, bls)*	Gross Layer Thickness (ft)	Net Layer Thickness (ft)	Porosity (percent)
Lower Cockfield	6045	345	145	24

\* At Wellbore location.

### **Layer Thickness**

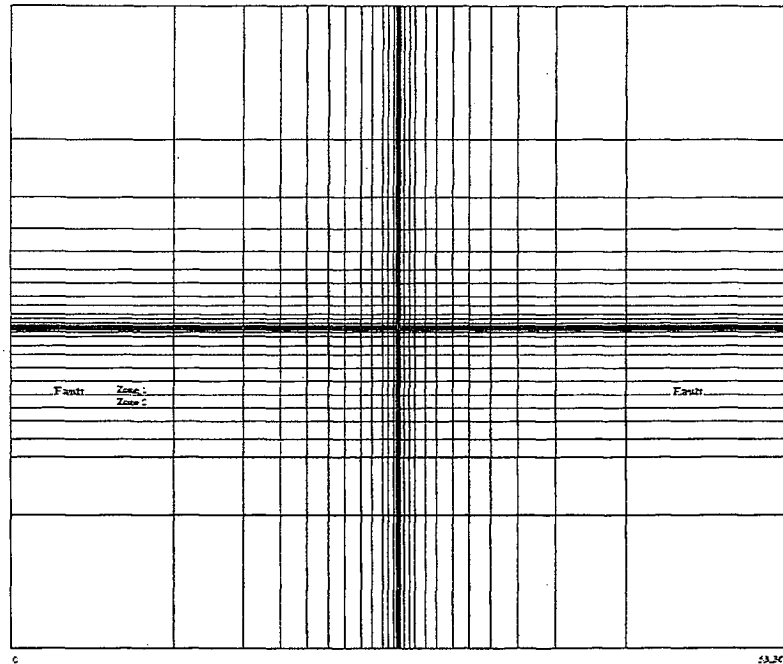
To determine appropriate thickness values of the injection reservoir geophysical logs were used. A total net layer zone thickness of 145 feet was identified for injection into the Lower Cockfield at the well location. (See Table 1) For the area past the fault identified in the geology review, a zero value for the sand thickness was used to simulate the EW-4400-S fault being a no-flow boundary in the model parameters.

### **Structure**

The geologic structure of the Cockfield was gathered from geologic structure maps pulled from the original WDW-315 application submitted in 1994 which was verified by ALL's geologist and based upon tops of the Cockfield identified in surrounding wells (see Figure V.B.1.7 in the TGD Class I well permit application). This supplied structure map was overlain with a data grid and used to create an injection reservoir structure for import into the model. Figure 1 presents the model grid developed for the WDW-315 model. This grid is the same grid that was utilized in the reservoir model in the TGD Class I well permit application.

**FIGURE 1**  
**Model Grid**

*Diagram of model grid with Fault line presented. Approximate 10x10 mile model area. Detailed grid-blocks around center masked due to scale of image. Zones presented are used in modeling efforts.*



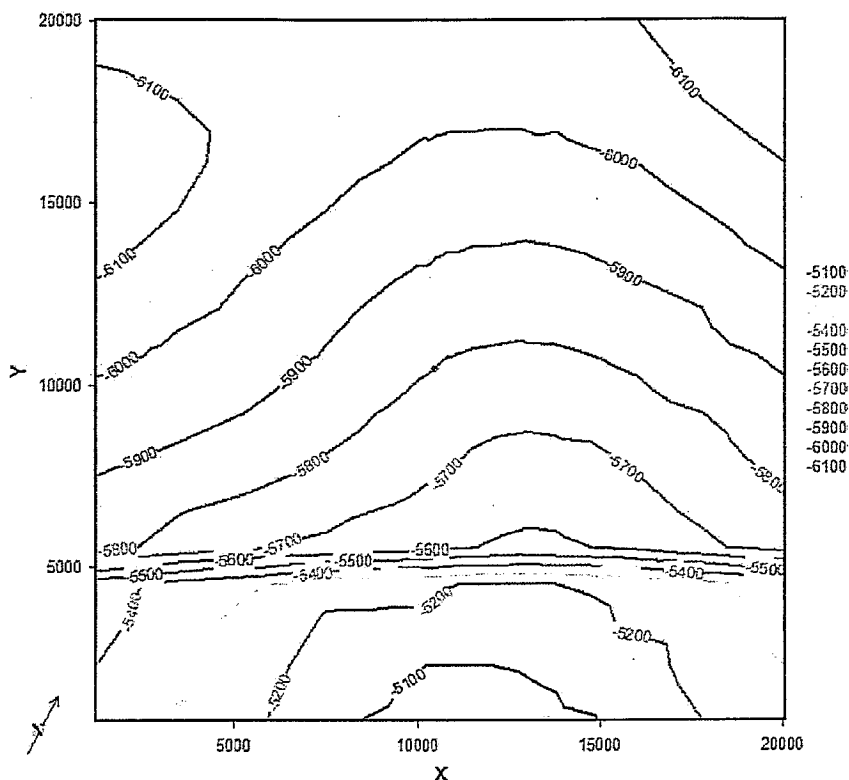
In the portion of the model grid presented above, the area north of the fault where the wellbore resides, the modeled injection reservoir contains only the Lower Cockfield formation. On the other side of the fault presented in Figure 1 the injection zone is removed from the model to simulate a zero transmissibility for the fault to the south of the injection well.

Figure 2 presents a structure map generated without structural edits from the model input data. This input data can be compared to the structural data presented in Figure V.B.1.7 of the TGD Class I well permit application.

**FIGURE 2**

**Structural Map of Area Surrounding Well**

*Developed structural map of the model area from contouring software and based on model input values.*



**Permeability and Skin**

Permeability is the capacity of porous media to transmit fluids. An averaged homogenous permeability of 80.9 md was determined from a well testing event performed after the initial well completion in December 1999. Based on review of the perforation record, log analysis, and core analysis performed on the well it is believed that the derived permeability from the well test analysis is not representative of the reservoir conditions. Estimates of reservoir permeability has been as high as 1,400 md based on literature review. Core analysis conducted on the Lower Cockfield indicated a permeability range of 550 md to 850 md for the portion of the formation planned for perforating after permit approval. A reservoir permeability of 500 md was used in the modeling effort presented in the TGD Class I permit application and is based on the review of logs and core analysis. This value is believed to be more representative of the injection zone and still considered to be a conservative number. However, in accordance with TCEQ's interim order dated December 12, 2008, the model presented in this report has been conducted at the lower permeability value of 80.9 md.

For modeling, a value of zero (0, no increase or decrease in effective flow conditions) was used for the model's skin factor as skin is a variable function over time and is dependent upon the condition of the wellbore.

### **Porosity**

Porosity is the ratio of void space in a given volume of rock to the total bulk volume of rock expressed as a percentage. The more porous a rock the more fluid can be stored in a given rock volume. A porosity value of 24% was used in the model relative to the Lower Cockfield zone. This value was derived from density, neutron, and sonic logging of the well and assuming a sand lithology.

### **Saturation and Relative Permeability**

From evaluation of the open-hole logs on the test well, water saturation in Cockfield formation is considered to be at 100%. Therefore, water relative permeability is 1.0.

### **Temperature**

A static reservoir temperature was measured in the wellbore at 6,200 ft of 185.85°F. This provides a gradient of 3.0°F per 100 feet of depth. This gradient was used to estimate temperature in the injection reservoir.

### **Compressibility**

Compressibility is the change in volume per unit increase in pressure. The rock compressibility was estimated to be  $3.7 \times 10^{-6} \text{ psi}^{-1}$  and the water compressibility was estimated at  $5.88 \times 10^{-6} \text{ psi}^{-1}$  from standard correlations (Earlougher, 1977).

### **Injection Reservoir Fluid**

The formation fluids in the Lower Cockfield are typical of producing formations in the Gulf Coast. The fluid is a brine with a high total dissolved solids (TDS) content (105,000 part per million (ppm)). The formation fluid was sampled after the original well completion in December 1999 and a copy of the analytical results is contained in Volume X – Well Completion Report in TGD's Class I injection well permit application.

## **Reservoir Model Parameters**

### **Model Construction**

The reservoir model constructed for pressure predictions is based on placing the well in an approximate 10-mile square model. The model is configured for infinite acting outer boundaries based on the large areal extent of the Cockfield Formation. The area was divided into a 25 block by 27 block by 1 layer grid block model of the underground injection area. The grid was proportioned in such a manner to have greater detail around the wellbore. The injection well was modeled in a

100-foot by 100-foot grid block with the grid block sizes increasing away from the wellbore to simulate the injection zone reservoir. Figure 1 represents the model grid used to represent the reservoir. The apparent thicker lines crossing at the center represent the smaller grid blocks radiating from the wellbore.

For this model run the blocks along the EW-4400 fault to the south of the well were configured as a closed boundary to simulate the condition that the fault is non-transmissive. In order to generate this model configuration, a two-step process was required to accurately simulate the boundary condition within the numerical model. First a separate model was constructed by using a reservoir similar to the Cockfield (i.e. inputting reservoir parameters) but without geologic structure applied to it. This was to simulate conditions assumed by the analytical models with a closed boundary condition. Using this model, the boundary condition input parameters were tested to ensure the numerical model simulation results matched expected results from the analytical model's output.

Once boundary conditions were developed to mimic the analytical results, these conditions were applied to the Lower Cockfield model using the geologic structure previously developed in the original well modeling effort depicted in Section VII of TGD's Class I injection well application with only the Lower Cockfield formation accepting fluid (no Middle Cockfield due to closed fault). The model was constructed in this two-step process due to the lack of historical reservoir pressure data for the well to provide history matching for the model. This was done to provide a better representation of the estimated pressure profiles after performing 30 years of constant injection.

### Model Input Parameters

Input parameters for the reservoir model were generated from geologic data, drilling logs, wireline logging, standard correlations, structural maps, and analysis of injection/fall off testing. A single layer was chosen to represent the reservoir in the numerical model. The following table provides a summary of the reservoir characteristics obtained from the above-mentioned sources and the values used in the modeling efforts for the represented the zone.

**TABLE 2**  
**Model Input Parameters**

Zone	Layer TOP Depth (ft, bls)*	Net Layer Thickness (ft)	Porosity %**	Permeability (md)	md-ft	Temperature (F)
1	6045	145	24	80.9	72,500	181

\* At Wellbore location.

\*\* For initial modeling effective considered same as total.

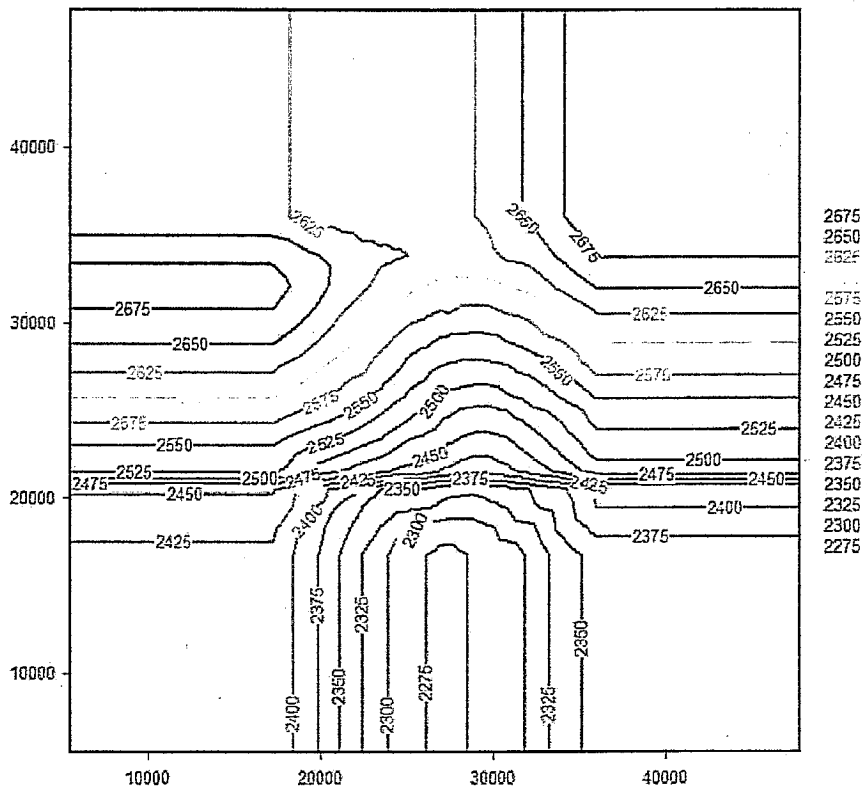
### Initial Static Reservoir Pressure

Data from the well testing event (12/17/1999) performed on the injection well was used for the initial static reservoir pressure, since there was no prior injection. At a depth of 6,200 feet a pressure of 2502.28 psi was measured. Using these numbers yields a pressure gradient in the wellbore of .404 psi/ft.

**FIGURE 3**

#### Pressure at Initialization

*Pressure contours at the initialization of the model.*



## Model Results

Whenever effluent is injected into a subsurface geological formation, the pressure within the reservoir used for injection will increase. This pressure increase will be greatest at the well and will decrease with distance away from the site.

The simulation model run for the proposed Lower Cockfield injection interval was made to predict average lateral pressure distributions for 30 years at the proposed maximum injection rate. For this modeling effort, the EW-4400-S fault was modeled as a non-transmissive fault. Table 3 provides a summary of the results of the BOAST98 modeling of the injection pressure buildup at the injection well.

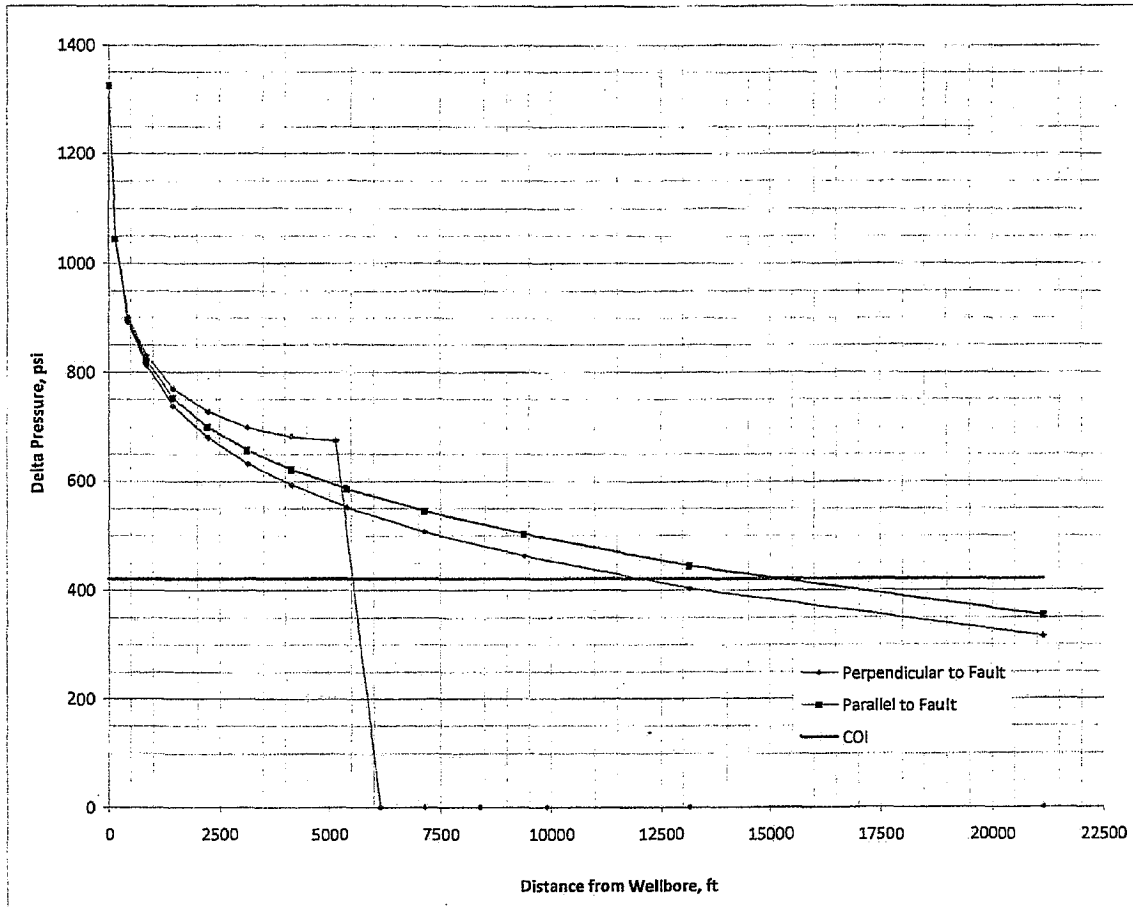
**TABLE 3**  
**Summary of Modeled Reservoir Maximum Injection Pressure at the Wellbore**

Time Step	Initial	30 years
Reservoir Pressure at Wellbore (psi)	2512	3897
Pressure Increase at Wellbore (psi)	0	1385

Figure 4 provides a summary graph of the change in reservoir pressure at distance from the injection well in the Lower Cockfield both parallel and perpendicular to the fault after 30 years of injection as simulated by the reservoir model. As is shown on the plot, the pressure in the formation remains higher parallel to the fault due to the simulated boundary which prevents fluid flow across the fault. The cone of influence value of 421 psi (TGD Class I injection well application, Section VII.F) is included on the graph to show the distance from the injection well where the pressure in the formation drops below the cone of influence pressure. The results show that, assuming a permeability of 80.9 md and a non-transmissive EW-4400-S fault, and making several other conservative assumptions, the cone of influence for the injection well would extend 15,500 feet from the well in an east-west direction and 12,000 feet towards the north of the well. To be additionally conservative, this AOR would be assumed to be 15,500 feet for the area north of the EW-4400-S fault.

A reservoir pressure distribution contour plot for year 30 is shown in Figure 5. The Time Step summary for each time period and the Total Run Summary of simulation are provided in the attached Modeling Reports in Appendix 1.

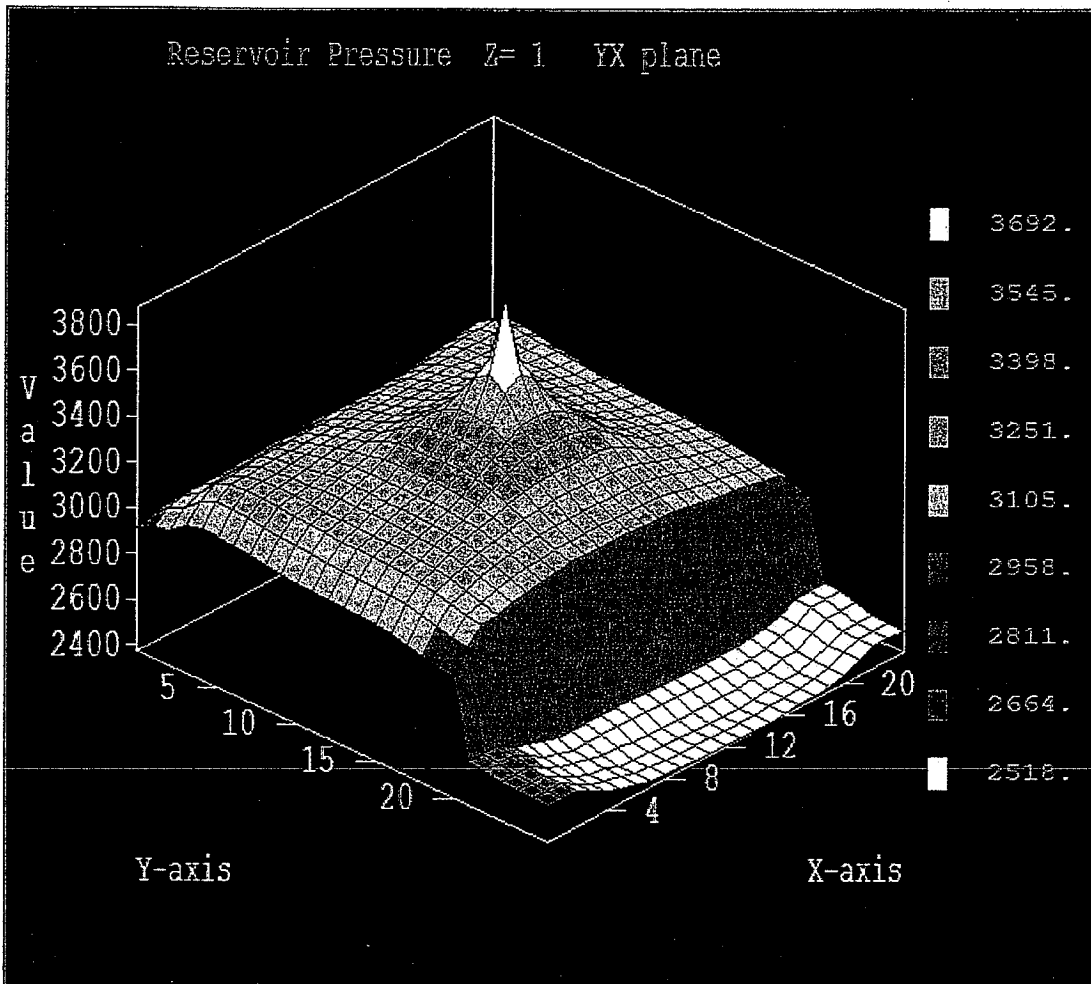
**FIGURE 4**  
**Pressure Profile in Injection Zone**  
*Plot of pressure change with distance from wellbore.*



**FIGURE 5**

**Pressure Year 30**

*Pressure contours after 30 years of modeled injection.*



### Area of Review

Under the Texas Administrative Code (TAC) §331.42(b)(1) standard, the Area of Review for a Class I injection well corresponds to the area within a fixed 2.5-mile radius of the injection well or based on the calculated "cone of influence" of the injection well, whichever is greater. The "cone of influence" is defined as "...the potentiometric surface area around the injection well within which increased injection zone pressures caused by injection of effluent would be sufficient to drive fluids into a USDW or freshwater aquifer" (TAC §331.2). The area of review for the TGD Class I well application was set at 2.5 miles. This modeling effort shows that, as a result of using the

conservative assumptions described above, the AOR would expand to 15,500 feet or 2.94 miles for the area north of the fault. In addition, the area to the south of the fault would be eliminated from the AOR due to the injection fluid being limited in the south direction by the non-transmissive fault.

Five hundred and five artificial penetrations were identified in the Area of Review for the TexCom facility in the TGD Class I Injection well permit application (Table VIII-1). Within the AOR that would be created by this modeling effort, this well count would be reduced by approximately 253 wells due to the removal of wells located south of the EW-4400-S fault. Additionally, the AOR would pick up 10 additional wells located north of the fault and between 2.5 miles and 2.94 miles from the TGD injection well.

### Area of Review Map

A base map showing the permit application identification number and location of the artificial penetrations in a 2.94-mile radius Area of Review is included as Figure 6.

### Well Data and Files

There are 10 wells located in the area between the 2.5-mile AOR in the TGD Class I Injection well permit application and a 2.94 mile AOR. These wells are primarily to the east of the injection well, with a couple of the wells located on the west side of the injection well. Copies of well files are located in Appendix 2.

**TABLE 3**

**Wells Located North of Fault and Between 2.5 Miles and 2.94 Miles from the TGD Injection Well**

Map ID #	Well Name	Survey	Location	Depth	Well Status
RM-1	Williams #1	WCRR A-645	750' FNL, 412' FWL	5068'	Unknown
RM-2	#5	C.T. Darby A-752			Unknown
RM-3	T.E. McDonald #1	C.T. Darby A-752		5100'	Unknown
RM-4	Cartwright #1	J.A. Davis A-188		5066'	Unknown
RM-5	Williamson #1 API # 339-30627	J.G. Smith A-539	660 FNWL, 660 FNEL	9250'	Dry Hole, Unknown
RM-6	W.F Newton #1	J.G. Smith A-539		6000' Proposed	Dry Hole, Unknown
RM-7	STD #75	T. Slade A-500		5060'	P&A
RM-8	STD #78	T. Slade A-500		5061'	P&A
RM-9	STD #3	T. Slade A-500		5260'	P&A
RM-10	STD #76	T. Slade A-500		5065'	P&A